ACCESSION #: 9002140045
LICENSEE EVENT REPORT (LER)

FACILITY NAME: McGuire Nuclear Station, Unit 1 PAGE: 1 OF 12

DOCKET NUMBER: 05000369

TITLE: A Reactor Trip Occurred Because Of A Clogged Strainer On Feedwater Pump A Speed Controller Caused By Water In The Oil System For Unknown Reasons
EVENT DATE: 01/08/90 LER #: 90-001-00 REPORT DATE: 02/07/90

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Alan Sipe, Chairman, TELEPHONE: (704) 875-4183
McGuire Safety Review Group

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: CB COMPONENT: ISV MANUFACTURER: B350
REPORTABLE NPRDS: Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On January 8, 1990, at 1015, a Unit 1 Turbine Trip/Reactor Trip occurred when both Main Feedwater Pumps (CFPs) tripped on low suction pressure. Unit 1 was operating in Mode 1 (Power Operation) at 100 percent power prior to the trip. A trouble alarm was received for CFP A speed controller and immediately CFP A started reducing speed. Operations personnel initiated a manual turbine runback to compensate for the loss of feedwater flow from CFP A. Then CFP A speed controller within minutes started increasing speed. This attributed to the low suction pressure that tripped both CFP A and B. The speed controller malfunction was due to the strainer in the controller becoming clogged with sludge. The speed controller control oil is supplied by the Feedwater Pump Turbine Lube and Hydraulic Oil (LF/LP) System which share the oil purifier in the Main Turbine Lubricating and Purification Oil (LT) System. There were several anomalies as plant equipment responded to the Turbine

Trip/Reactor Trip. Operations personnel implemented the Reactor Trip recovery procedure to recover from the transient. At 1148, Operations personnel made the required notification to the NRC. Unit 1 then entered a refueling outage for turbine repair. This event is assigned a cause of Other/Unknown because it could not be determined how excessive water in the LT and LF system resulted in sludge collecting in the strainer. Operations and Maintenance Engineering Services (MES) personnel are pursuing attempts to minimize the accumulation of sludge because of excess water in the LF and LT systems.

END OF ABSTRACT

EVALUATION:

Background

The Main Feedwater (CF) system [EIIS:SJ] takes the treated Condensate (CM) system [EIIS:SD] water, heats it further to improve the plant thermal cycle efficiency, and delivers it at the required flow rate, pressure, and temperature to the Steam Generators (SG) [EIIS:SG] for makeup.

The CF system uses two turbine [EIIS:TRB] driven feedwater pumps [EIIS:P] designated as A and B. Each CFP will trip when two out of three respective CFP suction pressure switches [EIIS:PS] open on a low-low suction pressure signal. At greater than 56 percent Turbine Generator [EIIS:TG] load, the loss of either CFP will initiate a Turbine generator runback signal. An automatic Turbine Trip is initiated on the loss of both CFPs.

If a Turbine Trip occurs above approximately 48 percent full power, the P-8 permissive interlock ensures there will be an automatic Reactor [EIIS:RCT] Trip.

The LT system [EIIS:TD] supplies oil to the Main Turbine and Generator bearings, turning gear [EIIS:TGR], thrust bearings, overspeed trip valve [EIIS:V], protective devices [EIIS:38], and the electro-hydraulic interface emergency trip valve. The system also purifies oil from the main oil reservoir [EIIS:PVR] and both CFP turbine oil tanks [EIIS:TK]. In addition, this system provides a backup source of seal [EIIS:SEAL] oil to the Generator Seal Oil System [EIIS:TI] if it is required.

The LT system is provided with an oil purifier [EIIS:PFR] and an oil transfer tank. The oil purifier is a centrifuge [EIIS:CEN] which separates entrained water and solids from the lubricating oil by centrifugal action. Dirty oil which contains up to 50 percent moisture content is purified to 0.1 percent moisture by volume and 0.02 percent solid by volume. The separated water will not contain more than 0.5 percent oil by volume. This oil purifier is shared between the LT and LF [EIIS:SL] systems.

The LF system supplies oil to the CFPs and CFP Turbine bearings and couplings and provides control oil to the CFP Turbine governor control, overspeed trip valve, low pressure steam governor and stop valve servomotors, and high pressure steam governor and stop servomotors.

The LP system [EIIS:JK] is the control oil supplied by the LF system and is used in the Lovejoy Speed Controller [EIIS:SC]. The Lovejoy Speed Controller controls the speed of the CFP. The Control oil flows through a Nugent filter [EIIS:FLT] housing with a nominal 5 micron, 6 inches by 36 inches cylindrical filter cartridge. Then the control oil flows through a one inch strainer [EIIS:STR] with 100 micron size mesh before flowing to the controller.

Description of Event

On January 3, 1990, around 1300, procedure OP/1/A/6250/01, Condensate And Feedwater, Enclosure 4.12, Placing/Removing CF Pump Control Oil (CUNO) Filters

In/From Service, was used to place Nugent filters 1A1 and 1B1 in service. The procedure requires the clean filters to be valved in before valving out the in-service dirty filters. Operations personnel verified visually that new filters had been placed in the filter housings of Nugent filters 1A1 and 1B1 before placing them into service. Approximately four hours after the filters were in service Operations personnel changed out the Lovejoy Speed Controller strainers and cleaned them. This was because through past experience Operations personnel have expected the strainers to clog within about 4 to 6 hours after placing new filters in service due to new filters releasing filter fines (loose filter media).

On January 7, 1990, the oil purifier in the LT system was switched from the main oil reservoir to the CFP A oil reservoir by Operations personnel. On January 8, 1990, around 0600, Operations personnel received a trouble alarm [EIIS:ALM] on the CFP A speed controller. This signaled to Operations personnel that the Lovejoy Speed Controller had a clogged strainer. Operations personnel changed out and cleaned the clogged strainer prior to shift change at 0730.

At 1013 on January 8, 1990, a trouble alarm was received on the CFP A speed controller again. Immediately, CFP A started slowing down with feedwater flow rapidly decreasing. CFP A discharge pressure dropped from 1039 psig to 678.5 psig between 1013:51 and 1014:26. CFP B increased to maximum flow to compensate for CFP A decreasing flow. At that time Operations personnel took manual control of the Turbine and ran it back to 600 MWe to compensate for the loss in feedwater flow from CFP A. Operations personnel also took manual control of CFP B to ensure that CFP B would stay at maximum speed. During this process, CFP A started to increase speed again. At 1014:37, the CFP A discharge pressure was at 689.3 psig and went to 1129 psig at 1015:30. This rapid increase in speed of CFP A required more suction flow to be supplied. At 1015:12, the indicated CM Booster pump suction pressure was low enough to auto start the standby Hotwell pump. However, the Standby Hotwell pump failed to auto start. The CM Booster pump did not auto start until after both CFPs tripped on low suction pressure at 1015:33. Therefore, at 1015:33 a Turbine Trip/Reactor Trip occurred. (The time listed for the CFPs tripping and the Turbine Trip/Reactor Trip occurring is based on the Events Recorder [EIIS:IQ] Data. The Events Recorder data is more accurate but limited to what information is available as compared to the Operator Aid Computer (OAC) [EIIS:ID] Alarm Summary data.) According to the OAC Alarm Summary, the CFPs, Turbine and Reactor tripped at 1015:51. The CM Booster pump did auto start about the same time that the CFPs tripped at 1015:51.

At 1015:51, a Low-Low SG level was received, thereby initiating the Auxiliary Feedwater system (CA) [EIIS:BA]. The CA pumps started as required. The CF containment isolation and CF to CA isolation valves started closing at 1015:51 due to the auto start of the CA pumps. Also, at 1015:51 the Main Steam [EIIS:SB] Power Operated Relief Valves (PORVs) and Main Steam line Code Safeties opened per their setpoint ranges except for valves 1SV-9, Main Steam 1C Safety No. 2, 1SV-15, Main Steam 1B Safety No. 2, and 1SV-21, Main Steam 1A Safety No. 2. Valve 1SV-9 and valve 1SV-15, opened earlier than their setpoint ranges as indicated on the OAC alarm summary. Valve 1SV-21 may have opened properly, but there was no indication on the OAC alarm summary signifying that it opened.

During coastdown of the Turbine, several anomalies occurred. Primary systems responded as expected to the transient. Maximum Pressurizer pressure was 2261 psig. As a result, no primary PORVs or Code Safeties were challenged. There was a slight overcooling event due to additional steam leakage which occurred around 1026. The cooldown of the primary system caused Pressurizer level to decrease to the Letdown isolation setpoint at 1026:25. Letdown attempted to isolate automatically; however, valve 1NV-1, Reactor Coolant Letdown Isolation To Regenerative Heat Exchangers, did not close and valve 1NV-459, A Letdown Orifice Outlet Containment Isolation, leaked by. Operations personnel manually increased charging flow and manually isolated valve 1NV-1 at 1026 and Pressurizer level was regained. The primary cooldown also caused a feedwater isolation at 1028 because of a reactor trip with low Tavg. Tavg was 541 degrees F and the cooldown was terminated by Operations personnel closing valve 1SM-15, Main Steam to Second Stage Reheaters, at 1028. Around 1100, primary temperature and pressure were stabilized at 557 degrees F and 2235 psig.

Around 1020 to 1021, the Turbine Seal Oil Backup Pump (SOBP), AC Turbine Bearing oil Pump (BOP), and Emergency Bearing Oil Pump (EBOP) auto started; however, there was negligible discharge pressure from the BOP and the EBOP. The Main Turbine Oil lift pump auto started when the turbine speed reached around 600 Revolutions per Minute (RPMs) according to the design. At 1030, Operations Control Room personnel were notified by Operations personnel of oil blowing from the main generator. Also at 1030, Operations personnel decided to manually vent the Hydrogen to atmosphere from the main generator to prevent any hydrogen leakage into the Turbine Building if the generator seals were lost. At 1035, Operations personnel turned off and manually bump started the EBOP. Operations personnel still did not observe any discharge pressure. At 1038:06 a 0 psig signal was received in the Control Room for Low Main Turbine Bearing Oil Pressure. Around 1039, Operations personnel tried turning off and bump starting the BOP and succeeded in getting normal discharge pressure. The Turbine indicated zero speed at 1049:43. Attempts made by Operations personnel to put the Turbine on turning gear failed.

At 1148 on January 8, 1990, Operations personnel made the required notification to the NRC according to procedure RP/0/A/5700/10, NRC Immediate Notification Requirements. On January 8, 1990, at 1445, Operations personnel made a follow-up notification to the NRC about the damage to the Main Turbine.

Conclusion:

This event is assigned a cause of Other/Unknown because it could not be determined how excessive water in the LT and LF system resulted in sludge instantaneously clogging the Lovejoy Speed Controller strainer. The strainer instantaneously becoming clogged with sludge caused the Lovejoy Speed Controller to lose its supply of control oil, causing CFP A to decrease in speed rapidly. Then within minutes sludge particles broke through the strainer or moved around enough allowing control oil to reach the Controller causing CFP A to increase in speed rapidly. The rapid fluctuation in flow from CFP A caused both CFP A and B to trip on low suction pressure. This caused the Reactor Trip.

The strainer did not fail. There was no deformation to the strainer except for being pushed in due to the momentary high differential pressure across it. MES and Operations personnel postulated that sludge accumulated on the strainer so quickly that oil flow to the CFP A control system was stopped. Eventually some of the particles were moved through or around the strainer allowing some oil to pass. A visual check by Operations personnel of the strainer showed that it was covered with sludge. Also the Nugent filters performed their intended function and had not deteriorated in any way. Operations personnel found sludge on the clean side of the filters. MES and Operations personnel theorize that some of this sludge broke loose and clogged the Lovejoy Speed Controller strainer.

Operations and MES personnel theorize that the sludge in the LF/LP system has been accumulating over a long period of time because of water and dirt in the oil systems (LT, LF and LP).

Moisture could be introduced into the LT system through steam leaking past the seals into the oil, moisture precipitating out of the air into the oil, and by water leaking from lube oil heat exchangers tube bundles. A water and oil mixture does not cause problems until the water separates due to changes in temperature or due to turbulence and collects in dead loops or at orifices [EIIS:OR]. The water collects with dirt and corrosion products producing sludge. Dirt is introduced into the oil systems (LT, LF, etc.) because the system is opened to the atmosphere and under a vacuum, because of corrosion particles, and because of normal wear on equipment.

The Nugent filter elements in use presently absorb water. After reaching saturation, occasionally water globules are expelled from the filter. The water oil mixture will not cause problems with the controller unless the water collects and develops sludge. MES personnel are investigating replacing the filters presently in use in the Nugent filter housings with filters that allow water to pass through, rather than absorbing it. This should prevent large amounts of water being expelled in large amounts from the filter and should allow the oil and water mixture to be maintained.

Procedure OP/1/A/6250/01, Condensate And Feedwater, Enclosure 4.12 is used to switch the in service filters. Approximately 2 years ago this procedure was enhanced by adding a step to ensure the filter housing was drained of all impurities prior to removing the dirty filter. Before this procedure change was implemented, Operations personnel did not drain the oil completely from the filter housing. Operations personnel theorize that this could have caused impurities to have been deposited from the dirty filter cartridge into the oil and possibly settling in the clean side of the filter housing. Operations personnel are ensuring the continued compliance of the Condensate and Feedwater Procedure Enclosure 4.12 by draining the filter housing as low as possible prior to removing the dirty filter on all future change outs. Operations personnel will evaluate adding a note to the Condensate and Feedwater Procedure enclosure 4.12 to reemphasize complete draining of the Nugent Filter Housing. MES and Operations personnel will establish necessary intervals for inspection and cleaning of the filter housings during future outages.

Maintenance personnel used a steam jet to clean the Nugent filter housings to ensure all sludge was initially removed and dried the housing with air. Maintenance personnel also purged with air the piping between the Nugent filter housings and the Lovejoy Speed Controller strainers to remove all sludge.

To address the problem of steam getting past the seals, MES personnel are investigating replacement of the steam seals presently installed with ones having tighter clearances to reduce the amount of steam entering the LT system.

Water leakage into the LT system has been excessive in the past; however, Maintenance personnel have inspected and repaired oil system heat exchangers and replaced oil cooler [EIIS:CLR] tube bundles in the LT system. After this maintenance, the coolant leakage had diminished greatly.

The LT system oil purifier removes water according to design requirements. It can clean the oil system to less than 0.1 percent moisture; however, this purifier is shared between the main turbine oil reservoir and the LF system CFP oil reservoirs. MES personnel plan to install an additional purifier system to be dedicated to service the LT system Main Turbine oil tank. The existing purifier will then be dedicated to purifying the LF system CFP oil reservoirs.

MES personnel plan to continue investigating ways of reducing water in the oil system which in turn should reduce sludge.

The Standby Hotwell pump did not auto start when it was required.

Operations personnel wrote Work Request 141830 to investigate and correct the problem on the Hotwell pump. MES personnel determined that pressure switch 1CMPS5551 (setpoint 65 psig) should have actuated during the event which would have auto started Hotwell Pump C. The Events Recorder printout shows that the pressure switch did not actuate even though the pressure was below the setpoint. Instrumentation and Electrical (IAE) personnel functionally verified correct operation of pressure switch 1CMPS5551, but found that the switch operated properly and opened at the correct setpoint. MES and IAE system expert personnel believe this pressure switch should have actuated during the transient. However, finding no problems with the pressure switch, IAE personnel replaced and calibrated it as a conservative measure.

The Standby Booster pump auto started at about the same time that the CFP A and B tripped. Operations personnel theorize that this was due to the transient being so rapid and the setpoint margin for starting the standby CM Booster pump (250 psig decreasing) and for ripping the CFPs (230 psig) are narrow. Operations personnel will evaluate a request for a larger margin in setpoints for starting the standby CM Booster pump and for tripping the CFPs.

Operations personnel will evaluate the development of guidelines for the Control Room Operator to use in future transients involving CFP fluctuations.

Operations personnel wrote Work Request 141826 to investigate the reason for valve 1NV-1 not closing during the transient. Upon investigation, IAE personnel determined that the actuator had an air leak which prevented the valve from closing. Maintenance personnel will repair the valve actuator according to Work Requests 07773A and 501993.

Maximum SG pressure was 1185 psig. All four Main Steam PORVs and two Code Safeties for all four SGs lifted as required. Performance personnel reviewing the Reactor Trip Transient stated that the only problems noted for SG pressure control were that Code Safety valves 1SV-9 and 1SV-15 opened approximately 10 psig below their setpoint and valve 1SV-21 failed to indicate opened. Performance personnel theorize that since the SG pressures closely following each other, that most likely all the No. 2 Code Safeties lifted at the proper pressure setpoint and that possibly the problem discovered during the transient is just an indication problem. Preventative Maintenance is being performed on valves 1SV-9, 1SV-15 and 1SV-21 to investigate and calibrate the pressure switches for the valves.

MES and Operations personnel determined that the reason for the BOP and the EBOP not developing a discharge pressure was due to the pumps being air bound. Maintenance personnel disassembled the pumps for inspection. Compliance personnel assigned a Problem Investigation Report PIR 1-M90-0025 to MES personnel to investigate and report the reasons for the BOP and EBOP not developing discharge pressure and causing Turbine Bearing damage. The damage to the Turbine bearings was quite severe. The Generator bearings were damaged and the low pressure turbine bearings were all damaged. The damage to the high pressure turbine and bearings is still being investigated.

A review of the Operating Experience Program data base for the past twelve months prior to this event revealed 2 events that were assigned the classification of Other/Unknown. These are Licensee Event Reports (LER) 370/89-01 and 369/89-04. LER 370/89-01 was a Reactor Trip that occurred during a Rod Cluster Control Assembly Movement Test. The rods [EIIS:ROD] dropped into the core due to an unknown cause. This event occurred on the primary side and is unrelated to this event. LER 369/89-04 was a Steam Generator Tube Rupture which resulted in a Primary-To-Secondary leakrate of 500 gallons per minute. These events involving Reactor Trips described above are not recurring based on the fact that they involved different systems and equipment. All three events are unrelated; therefore, this event is considered to be not recurring.

There were no personnel injuries, radiation overexposures, or uncontrolled releases of radioactive material as a result of this event.

CORRECTIVE ACTIONS:

Immediate: 1) Operations personnel implemented procedure EP/1/A/5000/01, Reactor Trip or Safety Injection, and then entered procedure EP/1/A/5000/1.3, Reactor Trip.

2) Station personnel contained and stopped the lube oil leak from the Turbine/Generator.

Subsequent: 1) Operations personnel removed and cleaned the Lovejoy Speed Controller strainer.

2) Operations personnel removed the Nugent filters and cleaned the filter housing.

3) Maintenance personnel disassembled the Nugent filter

housings and cleaned them with a steam jet and dried
them with air.

4) Maintenance personnel began purging with air all piping between the Nugent filter housings and the Lovejoy Speed Controller strainers of all sludge.

5) Operations personnel wrote Work Request 141830 to investigate the reason the Standby Hotwell pump did not auto start.

6) IAE personnel examined the Hotwell Pump Autostart pressure switch and found no problems. The pressure switch was replaced and calibrated as a conservative measure.

7) Maintenance personnel disassembled the BOP and the EBOP to investigate and repair as necessary any problems with the pumps.

8) Compliance personnel assigned PIR 1-M90-0025 to MES personnel to investigate and report the reasons for the BOP and EBOP not developing discharge pressure.

9) Operations personnel wrote Work Request 141826 to investigate the reason valve 1NV-1 failed to close.

10) IAE personnel determined valve 1NV-1 failure to close was due to an air leak on the actuator.

Planned: 1) MES, Project Services, and Operations personnel will install a new purifier system according to Nuclear Station Modification MG-12310.

2) MES personnel are evaluating replacement of the steam seals. The new seals will have tighter clearances.

3) MES personnel will investigate purchasing a different type of Nugent filter element according to McGuire Exempt Change Variation Notice (MEVN) 2190. The new filters will allow water to pass through rather than absorb water as the filters presently do.

4) MES personnel will continue investigating reduction

of water intrusion and sludge build-up in the LT
system.

5) Maintenance personnel will repair the air leak on the actuator for valve 1NV-1 according to Work Requests 07773A and 501993.

6) Operations personnel will evaluate adding a note to the Condensate and Feedwater Procedure Enclosure 4.12 to reemphasize complete draining of the Nugent Filter Housing.

7) MES and Operations personnel will establish necessary intervals for inspection and cleaning of the filter housings during future outages.

8) Operations personnel will evaluate a request for a larger margin in setpoints for starting the standby CM Booster pump and for tripping the CFPs.

9) Operations personnel will evaluate the development of guidelines for the Control Room Operator to use in future transients involving CFP fluctuations.

SAFETY ANALYSIS:

An analysis of transients and accidents postulated (e.g. Turbine Trip, Loss of Normal Feedwater Flow) which could result in a reduction of the capacity of the secondary system to remove heat generated in the Reactor Coolant System (RCS) [EIIS:AB] is presented in Section 15.3, Decrease In Heat Removal By The Secondary System, of the Final Safety Analysis Report (FSAR). For a Turbine trip event, Section 15.2.3 of the FSAR, the turbine stop valves close rapidly on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals as described in Section 10.2.2 of the FSAR. The automatic steam dump system would normally accommodate the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere and main feedwater flow would be lost. For this situation, feedwater flow would be maintained by the CA system to ensure adequate residual and decay heat removal capability. Should the steam dump system fail to operate, the steam generator safety valves may lift to provide pressure control.

Since 1970, the American Nuclear Society (ANS) classification of plant conditions has been used which divides plant conditions into four categories in accordance with anticipated frequency of occurrence and potential radiological consequences to the public. A Turbine trip is classified as an ANS Condition II event, a fault of moderate frequency. A loss of normal feedwater is classified as an ANS Condition II event, a fault of moderate frequency, also.

The loss of normal feedwater analysis (Section 15.2.7.2 of FSAR) is performed to demonstrate the adequacy of the reactor protection and engineered safeguards systems (e.g. CA) in removing long term decay heat and preventing excessive heatup

of the RCS with possible resultant RCS overpressurization or loss of RCS water. Following a loss of normal feedwater, CA is capable of removing the stored and residual heat, thus preventing either overpressurization of the RCS or loss of water from the reactor core, and returning the plant to a stabilized condition. Also, for a loss of normal feedwater, the steam dump to the condenser is assumed to be lost, heat removal from the secondary system then occurs through the steam generator power operated relief valves or safety valves. Since no fuel damage is postulated to occur, radiological consequences resulting from this transient would be less severe than the steamline break accident analyzed in Section 15.1.5.3 of the FSAR.

During this transient, the CA System operated as designed and ensured the shutdown of the unit to be safe and stabilized. The Steam Generator PORVs and the first 2 code safeties for all Steam Generators opened. Only one code safety valve 1SV-21, Main Steam 1A Safety No. 2, did not indicate as opening; however, Performance personnel stated that even though the Control Room indication did not show this valve opening that we had no reason not to suspect that the valve did indeed open. The SG pressure did not increase high enough to open the next three Code Safeties beyond the No. 2 Code Safeties.

The health and safety of the public were not affected by this incident.

ADDITIONAL INFORMATION:

Sequence Of Events

OAC - Operator Aid Computer Printout (Alarm Summary)
TRI - Transient/Reactor Trip Investigation Report
ER - Events Recorder
SSL - Shift Supervisor's Unit 1 Logbook

SEL - Shift Manager's Unit 1 Logbook
PR - Personnel Recollection
RTR - Transient/Reactor Trip Investigation Transient/Post-Trip
Review Report

Date Time Event

1/3/90 Approx. 1300 Procedure OP/1/A/6250/01, Condensate and
Feedwater, Enclosure 4.12 was used to place
Nugent filters 1A1 and 1B1 in service. (PR)

1/3/90 Approx. 1700 Approximately four hours after the filters were
in service, the Strainer on the Lovejoy Speed
Controller was changed out. (PR)

1/7/90 ---- Oil purifier system for CFP A was put into
service. (PR)

1/8/90 0600 Trouble Alarm on CFP A Speed Controller was
received signaling a clogged strainer on the
Lovejoy Speed Controller for the CFP A. (PR)

---- Before shift change Operations personnel changed
out and cleaned the clogged strainer. (PR)

1013 Trouble alarm was received on CFP A Speed
Controller. (PR)

1013:51 CFP A started slowing down. (OAC,SSL)

1013 Operations Control Room personnel took manual
control of the turbine to run it back to 600 MWe
and they took manual control of CFP B. (PR,SSL)

1014 CFP A started increasing. (OAC)

1015:12 The indicated CM Booster pump suction pressure
was below the setpoint (65 psig) for auto
starting the standby Hotwell Pump. (OAC)

1015:25 1C1 and 1C2 Heater Drain Tank Pumps tripped.
(ER)

1015:33 Both CFP A and B tripped on low suction pressure

(TRI,ER).

1015:33 Turbine Trip and Reactor Trip (TRI,ER,SEL,SSL)

1015:51 Booster Pump C auto started. (OAC,PR)

1015:51 Received a Low-Low SG level, thereby, initiating auxiliary feedwater systems. Auxiliary Feedwater pumps started and Feedwater Isolation occurred. (RTR,OAC)

1015:51 Main Steam Line PORVs and Code Safeties open per their setpoint ranges except for valves 1SV-9, 1SV-15, and 1SV-21. (OAC)

1020:07 SOBP came on. (OAC)

1020 BOP Auto Started but there was no discharge pressure. (PR)

1021:33 EBOP auto started but there was no discharge pressure. (OAC,PR)

1026 Pressurizer level decreased to the letdown isolation setpoint. (TRI)

1026 Letdown isolation occurred on low pressurizer level due to cooldown of primary systems. (SSL,PR)

1026 Operations personnel manually increased charging flow and manually isolated 1NV-1. (PR)

1028 Steam to Moisture Separator Reheaters through valve SM-15 was isolated.

1028 Feedwater Isolation Signal on Reactor Trip with Lo Tavg was received. (RTR,OAC)

1030 Operations Control Room personnel notified of oil blowing from main generator. (SSL)

1030 Operators manually dumped Hydrogen pressure from generator. (SSL)

1035 Operators manually switched off and on the EBOP. (PR)

1038 The Main Turbine Oil Lift Pump auto started. (RTR,PR)

1038:06 Received 0 PSIG signal for the Low Main Turbine Bearing Oil Pressure Alarm. (OAC)

1039:20 The BOP and the SOBP were on and providing oil pressure. (OAC)

1049:43 The turbine was at zero speed. (OAC)

Approx. 1100 Primary Temperature and Pressure stabilized. (SSL)

---- Attempts to put Turbine/Generator on turning gear have failed. (SSL)

1148 Operations personnel notified NRC per procedure RP/0/A/5700/10. (SS)

1445 Operations personnel followed up to NRC on damage to the Main Turbine. (SSL)

ATTACHMENT 1 TO 9002140045 PAGE 1 OF 2

Duke Power Company (704) 875-4000
McGuire Nuclear Station
P.O. Box 488
Cornelius, N.C. 28031-0488

DUKE POWER

February 7, 1990

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Subject: McGuire Nuclear Station Unit 1
Docket No. 50-369
Licensee Event Report 369/90-01

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a)(1) and (d), attached is Licensee Event Report 369/90-01 concerning a reactor trip due to a clogged strainer on the feedwater pump speed controller. This report is being submitted in accordance with 10 CFR 50.73(a)(2)(iv). This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

T.L. McConnell

DVE/ADJ/cbl

Attachment

xc: Mr. S.D. Ebneter American Nuclear Insurers
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LER Cover Letter
Page 2

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MC-815-04
(20)

*** END OF DOCUMENT ***